Chapter 4: Impacts of Natural Gas Scenarios for Meeting Future Demand

Natural gas will play a prominent role in meeting New England's energy needs in the future. The region's future gas supply needs must be met at a reasonable cost while maintaining high environmental standards. As shown in Chapter 3, the ability to deliver needed natural gas supplies, however, may be strained in future years. The objective of this chapter is to examine the impacts of different natural gas and other resource development and demand reduction scenarios on the region's future gas supply/demand balance.

Policy Objectives[54]

Reliability (of Fuel Delivery Infrastructure)

Reliability in this report refers to the ability of the natural gas and the electricity systems to deliver natural gas and electricity when and where they are needed in New England.

The analysis below measures reliability in terms of the ability of the natural gas delivery system to provide peak winter day natural gas supplies. We describe this policy goal in qualitative terms and consider the ability of infrastructure (pipelines and gas storage) to provide (or offset) both vapor and liquid in serving peak day gas needs.

Fuel Diversity (of fuel types and fuel sources)

Fuel diversity in this report refers to a balanced energy portfolio without heavy reliance on any one particular fuel type or source.

Fuel diversity helps protect consumers against the threat of supply disruptions and price volatility. It also provides increased energy reliability through reduced chances of supply or delivery interruptions.

Price Mitigation

Price mitigation in this report refers to lowering energy prices.

In the case of natural gas, the region could experience economic disadvantages if constrained natural gas supplies or increased natural gas demand cause New England's natural gas prices to increase dramatically over the long run.

Price Stabilization

Price stabilization in this report refers to the avoidance of price spikes and price volatility. Energy price volatility refers to unexpected variations in price, not price movements that are the norm for different seasons.

[54] There are other policy goals not considered in this report, most notably environmental goals. The energy policy goals discussed here are those within the expertise of the Power Planning Committee. They are a subset of those that must be considered in the formulation of overall public policies on resource development and demand reduction scenarios.

The major price risk associated with uncertainty of natural gas supplies, and with gas-fired electric generation is price volatility, especially in winter months.

<u>Security (of fuel supplies and delivery infrastructure)</u>

Security means the ability of the natural gas delivery system to avoid sudden losses or interruptions in supplies due to criminal, terrorist, and other intentional acts of destruction. It also includes the ability to avoid costs associated with preventing or mitigating the occurrence of such events though we do not include a quantitative comparison of these costs.

Assuring secure delivery of energy supplies and public safety has become an even more important policy objective in recent times.

Resource Development Scenarios

Keeping in mind the above policy considerations, we seek to evaluate possible future resource development and demand reduction scenarios. We have selected nine scenarios that represent reasonable expansions of current activities, currently proposed developments or alternative technologies that might be proposed in the foreseeable future. We describe these below.

Expansion of Fuel Switching—This scenario assumes that gas plants will be able to switch to oil for limited periods for the purpose of serving peak day demand.

Expansion of Energy Efficiency Programs—This scenario assumes that new electric energy efficiency programs, beyond those currently in place and included in our high peak day gas use forecast, come on-line to provide significant decreases in the need to dispatch gas-powered electric generators. These new programs consist of implementing upgraded building energy codes, adopting more stringent appliance and product efficiency standards, and using additional energy efficiency measure to offset load growth.[55]

Renewable Electric Generation—This scenario assumes construction of renewable electricity generation that has not been included in our high peak day gas use forecast. Specifically, we assume that the renewable performance standard (RPS) in Massachusetts, Connecticut, and Rhode Island are met, resulting in renewable generation construction to represent 7%, 7%, and 6.5%, of retail sales in the respective states by 2012.

On-Shore, In-Region LNG Expansion—This scenario consists of adding marine receipt of LNG and expansion of vaporization facilities in order to increase the volumes of vapor injected into the pipeline system and maintain or increase the volumes of liquid transported by trucks to other storage

[55] The source for the energy efficiency costs and savings is "Economically Achievable Energy Efficiency Potential in New England," NEEP, 2004. That study also provided analyses of further expansion of electric energy efficiency programs than included in this study to achieve even greater savings. Inclusion of such a scenario would provide greater peak-day benefits and come at greater costs. We would have liked to include the impacts of gas energy-efficiency programs, but data on the effectiveness of these programs were unavailable or incomplete.

facilities within the region. An example of such a project is the Keyspan expansion proposal in Providence, Rhode Island.

On-Shore, In-Region LNG—This scenario includes construction of one or more on-shore LNG terminals that is able to receive liquid, and either vaporize the liquid for injection into the pipeline system or transport the liquid using trucks to existing storage facilities around the region. An example of such a project is the Weaver's Cove proposal in southeastern Massachusetts.

Off-Shore, In-Region LNG—This scenario consists of construction of one or more off-shore receiving terminals, whereby a specially-equipped LNG tanker would dock off-shore and deliver vapor through a pipeline to the mainline infrastructure system. An example of such a project is the Northeast Gateway proposal off the coast of northern Massachusetts.

On-Shore, Out-of-Region LNG—This scenario consists of construction of one or more on-shore LNG terminals that is able to receive liquid and vaporize liquid for injection into the pipeline system but is not capable of trucking liquid to storage terminals due to its remote location. An example of such a project is the Anadarko Bear Head project in Nova Scotia, Canada.

Coal Gasification Expansion—This scenario assumes construction of a new coal gasification plant.

Nuclear Generation Expansion—This scenario assumes construction of a new nuclear generation plant.

The scenarios do not include one for natural gas pipeline expansion only. There have been pipeline expansions proposed for regions contiguous to New England, but these do not add to the *deliverability* of supplies into the New England region. These out-of-region pipeline projects should aid in the *availability* of supplies that can be delivered to the New England region as supply gets added through additional LNG expansion in the Gulf Coast and along the southern East Coast. All of the LNG scenarios discussed below would deliver additional vapor to the New England pipeline network and may result in some pipeline expansion (e.g. to accommodate the additional vapor from LNG). In the case of one scenario, on-shore, out-of-region LNG, we include pipeline expansion costs, which would be incurred to increase delivery of vapor to the region.

Scenario Analysis

The goal of this analysis is not to provide a detailed quantitative evaluation of the benefits and costs of development scenarios. It is beyond the scope of this paper and available information and modeling resources to provide such an analysis. Rather, we seek to uncover a number of key points and examine the relative contributions to achieving reliable service at reasonable costs. Thus, we provide on the following pages a qualitative analysis of the reliability, fuel diversity, price, and security impacts of these scenarios compared to the "no development" scenario that is described in the previous chapter.

The impacts of each scenario relative to the "no development" scenario are described in terms of impacts on (a) assuring reliable delivery of fuel supplies (b) improving fuel diversity (c) mitigating prices and stabilizing prices and (d) security concerns and costs associated with the scenario. In addition, we provide a quantitative estimate of the contributions of each option to meeting the region's peak day demand for natural gas through 2012. Finally, where available, we present the levelized capital costs per gas unit[56] delivered. These costs help to indicate the relative magnitude of the costs that would be borne by the region with each resource development or demand reduction scenario.

[56] We only include capital and fuel costs involved with each option. We do not include operations and maintenance costs due to their relatively small portion of total costs. Finally, we do not include any pipeline tariff data, instead relying on the capital costs of necessary pipeline projects as a rough proxy for tariff rates.

Expanded Switching of Gas/Oil Fired Power Plants to Oil

Reliability—There are almost 6,000[57] MWs of gas-fired generation in New England that are permitted to switch from using natural gas to using oil, for limited periods of time (e.g. 30 days) while still meeting emission restrictions. (Our no development scenario assumes none of this capacity switches to using oil during peak gas demand periods.) The reserve margins found in Table 4-1 assume that 1,000 MWs of gas-powered electric generation switches to oil starting in 2006 on all peak demand days. The reductions in peak day demand for gas that results from this scenario improves gas reserve margins. Reserve margins with vaporization under both normal and high demand levels are positive through 2012. After vaporization, normal demand results in negative reserve margins from 2009 through 2012 and under high demand level reserve margins are negative in all years through 2012.

Table 4-1
Reserve Margins Assuming Expansion of Fuel Switching Capability
2005-2012
(Bcf/day)

	2005	2006	2007	2008	2009	2010	2011	2012
	With Vaporization							
Normal Demand	1.25	1.37	1.28	1.36	1.27	1.17	1.07	0.96
High Demand	0.76	0.84	0.71	0.74	0.61	0.46	0.31	0.15
	After Vaporization							
Normal Demand	0.03	0.15	0.06	0.08	(0.01)	(0.11)	(0.21)	(0.32)
High Demand	(0.46)	(0.38)	(0.51)	(0.54)	(0.67)	(0.82)	(0.97)	(1.13)

Fuel Diversity—Though fuel switching implies fuel diversity, this scenario may exacerbate the region's dependence on oil. Oil plays just as critical a role as natural gas in serving winter space heating needs in New England, hence there may be no net benefits in terms of fuel diversity There may be simply a reduction in dependence on one fuel and in increase in another. However, there may be benefits if oil is bought and stored prior to winter.

Natural Gas Price Mitigation and Stabilization-- There is potential for this scenario to reduce natural gas prices because demand for natural gas from electric generators is reduced. However, uncertainty remains due to the doubt in the ability of regional projects to influence prices that may be determined on a national or international level. A greater amount of fuel switching should result in greater potential for impacts on natural gas prices.

Security-- Examining the security impacts of this option involves comparing the relative security concerns related to fuel delivery. Additional on-site storage and the transport of oil may pose a security concern for many of the same reasons as does LNG.

Cost—The fuel switching option provides gas displacement in 2006 at a cost of $1.18 million/Bcf and falls to $604,000/Bcf in 2012 due to decreases in the price of distillate fuel compared to natural

[57] ISO-NE

gas over that time period. This assumes that no additional capital cost is needed to retool the plant or the fuel delivery system.

Expansion of Electric Energy Efficiency Programs

Reliability—Expansion of electric energy efficiency programs reduces the demands for electric generation, thus reducing the potential peak needs of electric generating plants. Gas plants were assumed to be on the margin in the dispatch of electric generation in the region and thus would be displaced by energy efficiency measures. However, because electric generation is a modest component of overall peak day gas demand, increased efficiency in electricity consumption provides only a modest improvement in gas supply reserve margins. Reserve margins for this scenario are shown in Table 4-2. Reserve margins are positive through 2012 with vaporization. After vaporization, under normal gas demands, margins are positive only through 2006 and under high gas demands are negative for all years through 2012.

Table 4-2
Reserve Margins Assuming Electric Energy Efficiency Expansion
2005-2012
(Bcf/day)

	2005	2006	2007	2008	2009	2010	2011	2012
	With Vaporization							
Normal Demand	1.30	1.23	1.16	1.26	1.19	1.12	1.05	0.97
High Demand	0.81	0.70	0.60	0.64	0.53	0.41	0.29	0.16
	After Vaporization							
Normal Demand	0.08	0.01	(0.06)	(0.02)	(0.09)	(0.16)	(0.23)	(0.31)
High Demand	(0.41)	(0.52)	(0.62)	(0.64)	(0.75)	(0.87)	(0.99)	(1.12)

Fuel Diversity—This scenario results in considerable fuel diversity benefits because electric energy efficiency measures lead to reductions in all types of fuel use.

Natural Gas Price Mitigation and Stabilization-- There is potential for this scenario to reduce natural gas prices because demand for natural gas from electric generators is reduced. However, uncertainty remains due to the doubt in the ability of regional reductions in gas demand to influence prices that may be determined on a national or international level.[58] There is no price volatility due to expansion of electric energy efficiency measures, thus providing benefits relative to the "no development" case.

Security-- Security concerns with this scenario are negligible, and security may actually improve, because it reduces the need for centralized generation.

Cost—Expansion of electric energy efficiency programs results in additional capital costs for the measures of about $2.86 billion over 20 years. This level of investment provides gas displacement at

[58] There has been recent work that has attempted to quantify the price-related benefits of both renewables and energy efficiency expansion. See, for example, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency", Lawrence Berkeley National Laboratory, January 2005.

a cost of $2.82[59] million/Bcf on average. Note that these investments would result in significant benefits to electric system users.[60] In addition, the gas that would otherwise have been used by electric generators that is displaced by these measures further help offset these costs.

---

[59] This calculation uses the $2.8 billion present value cost figure taken from the 2004 NEEP study and assumes an average of 15 years for the life of the energy efficiency measures. The annual Bcf savings for the energy efficiency measures was calculated to be 68 Bcf.

[60] The previously mentioned 2004 NEEP study shows positive benefit-cost ratio for this option in excess of 3.0.

Expansion of Electric Generation with Renewable Fuels

Reliability—Replacing growth in non-gas-fired electric generation, specifically with renewables, results in lower peak day gas demand, assuming these plants can get sited, financed, and dispatched. Assuming an additional 1,098 MW of new renewables[61] by 2012, operating at 50% capacity factor, reserve margins are shown in Table 4-3. Addition of renewables at this level results in no negative reserve margins with vaporization capability. However, the additional gas displaced is not enough to account for loss of vaporization.

Table 4-3
Reserve Margins Assuming Renewable Electric Generation Expansion
2005-2012
(Bcf/day)

	2005	2006	2007	2008	2009	2010	2011	2012
	With Vaporization							
Normal Demand	1.27	1.19	1.12	1.21	1.13	1.06	0.98	0.89
High Demand	0.78	0.66	0.55	0.60	0.48	0.36	0.22	0.08
	After Vaporization							
Normal Demand	0.05	(0.03)	(0.10)	(0.07)	(0.15)	(0.22)	(0.30)	(0.39)
High Demand	(0.44)	(0.56)	(0.67)	(0.68)	(0.80)	(0.92)	(1.06)	(1.20)

Fuel Diversity—This scenario results in considerable fuel diversity benefits because renewable technologies either use no fuel (e.g., wind) or a different fuel (e.g., wood) whose pricing and sources are quite different than traditional pipeline gas sources.

Natural Gas Price Mitigation and Stabilization—There is potential for this scenario to reduce natural gas prices because demand for natural gas from electric generators is reduced. In addition, renewable generating technologies either feature no price volatility (due to no fuel use) or minimal price volatility (due to use of a stable-priced fuel), thus there is potential for reducing price volatility as well. However, uncertainty remains due to the doubt in the ability of regional projects to influence prices that may be determined on a national or international level.[62]

Security—Security concerns with this scenario are minimal, especially for those renewable technologies that feature little or no fuel use and therefore delivery.

Cost—Expansion of renewable generation results in additional electric-related capital costs[63] of $1.55 billion. This scenario provides gas displacement at a cost of $4.5 million/Bcf. These capital costs would be offset by lower fuel costs due to the reduction in natural gas usage by gas-fired generators. This is true even after accounting for fuel costs for biomass technologies.

---

[61] New renewables mix consists of equal percentages of wind, biomass, and landfill gas.
[62] There has been recent work that has attempted to quantify the price-related benefits of both renewables and energy efficiency expansion. See, for example, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency", Lawrence Berkeley National Laboratory, January 2005.
[63] Assumptions for capital cost from AEO 2004.

Expansion of On-Shore, In-Region LNG Delivery and Storage

Reliability—The on-shore, in-region LNG expansion option provides reliability related impacts in two forms—(a) injection of vapor into the pipeline system after vaporization of LNG, and (b) ability to transport liquids to storage facilities for future use. The reserve margins due to the addition, in 2007, of a project of the scope and size of the KeySpan Expansion project[64] are shown in Table 4-4. These reserve margins remain positive through 2012 under both demand levels with vaporization. After vaporization, reserve margins remain positive through 2010, but only marginally so. Under a high demand level, after vaporization reserve margins are negative for all years through 2012.

Table 4-4
Reserve Margins Assuming On-Shore, In-Region LNG Delivery and Storage
2005-2012
(Bcf/day)

	2005	2006	2007	2008	2009	2010	2011	2012
With Vaporization								
Normal Demand	1.25	1.17	1.46	1.53	1.44	1.35	1.25	1.14
High Demand	0.76	0.64	0.89	0.92	0.79	0.64	0.49	0.33
After Vaporization								
Normal Demand	0.03	(0.05)	0.24	0.25	0.16	0.07	(0.03)	(0.14)
High Demand	(0.46)	(0.58)	(0.33)	(0.36)	(0.49)	(0.64)	(0.79)	(0.95)

Fuel Diversity—Expansion of LNG import capability does have fuel diversity benefits, even though LNG is simply natural gas in liquid form. LNG sources are different than traditional pipeline sources from eastern and western Canada and the U.S. Gulf Coast, thus introducing more options for supply. In addition, this resource development scenario permits trucking of gas in liquid form throughout New England, thus providing a different fuel due to the fact that it can be stored for later use as compared to vapor that cannot be stored in New England.

Natural Gas Price Mitigation and Stabilization—Price-related impacts will depend on the contracts underlying the development scenario and the level of out-of-region demands for LNG shipments. If out-of-region demand is strong and LNG cargoes are priced according to spot or index prices, then there will be few benefits of this scenario in terms of lower and/or more stable prices. On the other hand, if LNG terminal operators are able to secure long-term contracts at prices lower than pipeline-delivered prices and pass these terms along to customers, then the region will enjoy some price mitigation and more stable prices.

Security—This option, especially if located next to population centers, poses many safety concerns, which will differ depending on the facility's specific situation. The LNG ships which carry the product are subject to stringent construction and operational regulations (see LNG Safety and Security discussion on pages 7-8). In December 2004, the Sandia National Laboratories issued a report (the "Sandia Report") on the risks and safety implications of a LNG spill over water. That

[64] Keyspan data from FERC docket No. CP04-223-000. Project assumed to provide 0.375 Bcf/day at a capital cost of $75 million.

report found that accidental LNG spills, such as from collisions and groundings, are small and manageable under existing safety policies and practices. The report further determined that risks from intentional events, such as acts of terrorism, can be significantly reduced with appropriate security, planning, prevention, and mitigation. The hazards associated with specific sites will vary as a function of the proximity of people, buildings, traffic and other conditions. However, in general, the severity of the risks declines as the terminal sites are located away from population centers and the number and costs of required on-shore security measures (e.g. police and fire protection) similarly diminish with the distance from urban population concentrations.

Cost—The levelized capital cost per Bcf is $106,000/year for 20 years. However, when the cost of gas[65] is added, this scenario results in a cost of gas displacement of $5.77 million/Bcf.

[65] This calculation assumes an average of $5.66/mmbtu for the cost of natural gas over the study period. This is based on the natural gas prices found in Appendix C.

Expansion of On-Shore, In-Region LNG Delivery

Reliability—The on-shore, in-region LNG delivery option provides reliability-related impacts in two forms—(a) injection of vapor into the pipeline system after vaporization of LNG, and (b) ability to transport liquid to storage facilities for future use. The reserve margins due to the addition, in 2007, of a project of the scope and size of the Weaver's Cove[66] project are shown in Table 4-5. These remain positive through 2012 under both demand levels with vaporization. After vaporization reserve margins remain positive through 2010, but only marginally so. Under a high demand level, after vaporization reserve margins are negative for all years through 2012.

Table 4-5
Reserve Margins Assuming On-Shore, In-Region LNG Delivery
2005-2012
(Bcf/day)

	2005	2006	2007	2008	2009	2010	2011	2012
	With Vaporization							
Normal Demand	1.25	1.17	1.68	1.76	1.67	1.57	1.47	1.37
High Demand	0.76	0.64	1.12	1.15	1.01	0.87	0.71	0.56
	After Vaporization							
Normal Demand	0.03	(0.05)	0.46	0.48	0.39	0.29	0.19	0.09
High Demand	(0.46)	(0.58)	(0.10)	(0.13)	(0.27)	(0.41)	(0.57)	(0.72)

Fuel Diversity—Expansion of LNG import capability does have fuel diversity benefits, even though LNG is simply natural gas in liquid form. LNG sources are different than traditional pipeline sources from eastern and western Canada and the U.S. Gulf Coast, thus introducing more options for supply. In addition, this resource development scenario permits trucking of gas in liquid form throughout New England, thus providing a different fuel due to the fact that it can be stored for later use as compared to vapor that cannot be stored in New England.

Natural Gas Price Mitigation and Stabilization—Price-related impacts will depend on the contracts underlying the development scenario and the level of out-of-region demands for LNG shipments. If out-of-region demand is strong and LNG cargoes are priced according to spot or index prices, then there will be few benefits of this scenario in terms of lower and/or more stable prices. On the other hand, if LNG terminal operators are able to secure long-term contracts at prices lower than pipeline-delivered prices and pass these terms along to customers, then the region will enjoy some price mitigation and more stable prices.

Security—This option, especially if located next to population centers, poses many safety concerns, which will differ depending on the facility's specific situation. The LNG ships which carry the product are subject to stringent construction and operational regulations (see LNG Safety and Security discussion on pages 7-8). In December 2004, the Sandia National Laboratories issued a report (the "Sandia Report") on the risks and safety implications of a LNG spill over water. That

[66] Weaver's Cove data from Expanded Environmental Notification to MA MEPA. Project assumed to provide 0.6 Bcf/day at a capital cost of $350 million.

report found that accidental LNG spills, such as from collisions and groundings, are small and manageable under existing safety policies and practices. The report further determined that risks from intentional events, such as acts of terrorism, can be significantly reduced with appropriate security, planning, prevention, and mitigation. The hazards associated with specific sites will vary as a function of the proximity of people, buildings, traffic and other conditions. However, in general, the severity of the risks declines as the terminal sites are located away from population centers and the number and costs of required on-shore security measures (e.g. police and fire protection) similarly diminish with the distance from urban population concentrations.

Cost—The levelized capital cost per Bcf is $308,000/year for 20 years. However, when the cost of gas[67] is added, this scenario results in a cost of gas displacement of $5.97 million/Bcf.

[67] This calculation assumes an average of $5.66/mmbtu for the cost of natural gas over the study period. This is based on the natural gas prices found in Appendix C. The capital cost figure was obtained by assuming a 20-year life and 10% rate of return divided by an annual Bcf number of approximately 134 Bcf. This Bcf calculation assumes that this LNG option operates at similar capacity utilization levels as Distrigas. This method was also used for the other LNG scenarios.

Creation of LNG Delivery, In-Region But Off-Shore

Reliability—The off-shore, in-region LNG option provides reliability-related impacts through injection of gas vapor into the pipeline system after vaporization of LNG from an off-shore vessel. The reserve margins due to the addition, in 2007, of a project of the scope and size of the Northeast Gateway[68] project are shown in Table 4-6. Reserve margins would be positive through 2012 under both scenarios with vaporization. Under the after vaporization scenarios, reserve margins remain negative or are only barely positive through 2012.

Table 4-6
Reserve Margins Assuming In-Region, Off-Shore LNG
2005-2012
(Bcf/day)

	2005	2006	2007	2008	2009	2010	2011	2012
	With Vaporization							
Normal Demand	1.25	1.17	1.50	1.58	1.49	1.39	1.29	1.19
High Demand	0.76	0.64	0.94	0.97	0.83	0.69	0.53	0.38
	After Vaporization							
Normal Demand	0.03	(0.05)	0.28	0.30	0.21	0.11	0.01	(0.09)
High Demand	(0.46)	(0.58)	(0.28)	(0.31)	(0.45)	(0.59)	(0.75)	(0.90)

Fuel Diversity—Expansion of LNG import capability provides fuel diversity benefits, even though LNG is simply natural gas in liquid form. LNG sources are different than traditional pipeline sources from eastern and western Canada and the U.S. Gulf Coast, thus introducing more sources for supply.

Natural Gas Price Mitigation and Stabilization—Price-related impacts will depend on the contracts underlying the development scenario and the level of out-of-region demands for LNG shipments. If out-of-region demand is strong and LNG cargoes are priced according to spot or index prices, then there will be few benefits of this scenario in terms of lower and/or more stable prices. On the other hand, if LNG terminal operators are able to secure long-term contracts at prices lower than pipeline-delivered prices and pass these terms along to customers, then the region will enjoy some price mitigation and more stable prices.

Security—The LNG ships which carry the product are subject to stringent construction and operational regulations (see LNG Safety and Security discussion on pages 7-8). In December 2004, the Sandia National Laboratories issued a report (the "Sandia Report") on the risks and safety implications of an LNG spill over water. That report found that accidental LNG spills, such as from collisions and groundings, are small and manageable under existing safety policies and practices. The report further determined that risks from intentional events, such as acts of terrorism, can be significantly reduced with appropriate security, planning, prevention, and mitigation. The hazards associated with specific sites will vary as a function of the proximity of people, buildings, traffic and other conditions. However, in general, the severity of the risks declines as the terminal sites are located away from population centers and the number and costs of required on-shore security

[68] Northeast Gateway project data provided by Excelerate Energy. Project assumed to provide 0.42 Bcf/day at a capital cost of $400 million, which includes the cost of the ship, deepwater port facility, and necessary pipeline interconnection.

measures (e.g. police and fire protection) similarly diminish with the distance from urban population concentrations.

Cost—The levelized capital cost per Bcf is $503,000/year over 20 years. However, when the cost of gas[69] is added, this scenario results in a cost of gas displacement of $6.17 million/Bcf.

[69] This calculation assumes an average of $5.66/mmbtu for the cost of natural gas over the study period. This is based on the natural gas prices found in Appendix C.

Creation of LNG Delivery and Storage On-Shore But Out-of-Region

Reliability—The on-shore, out-of-region storage scenario provides reliability-related impacts in two forms—(a) injection of vapor into the pipeline system after vaporization of LNG, and (b) ability to transport liquid to storage facilities for future use. The reserve margins due to the addition, in 2007, of a project of the scope and size of the Anadarko's Bear Head project[70] near the Strait of Canso, Nova Scotia, Canada are shown in Table 4-7. Reserve margins are positive through 2012 under both normal and high demand with vaporization. After vaporization, they are marginally positive in some years under normal demand level and remain negative under high demand levels.

Table 4-7
Reserve Margins Assuming On-Shore, Out-of-Region Storage
2005-2012
(Bcf/day)

	2005	2006	2007	2008	2009	2010	2011	2012
	With Vaporization							
Normal Demand	1.25	1.17	1.44	1.52	1.43	1.33	1.23	1.13
High Demand	0.76	0.64	0.88	0.91	0.77	0.63	0.47	0.32
	After Vaporization							
Normal Demand	0.03	(0.05)	0.22	0.24	0.15	0.05	(0.05)	(0.15)
High Demand	(0.46)	(0.58)	(0.34)	(0.37)	(0.51)	(0.65)	(0.81)	(0.96)

Fuel Diversity—Expansion of LNG import capability provides fuel diversity benefits, even though LNG is simply natural gas in liquid form. LNG sources are different than traditional pipeline sources from eastern and western Canada and the U.S. Gulf Coast, thus introducing more options for supply.

Natural Gas Price Mitigation and Stabilization—Price-related impacts will depend on the contracts underlying the development scenario and the level of out-of-region demands for LNG shipments. If out-of-region demand is strong and LNG cargoes are priced according to spot or index prices, then there will be few benefits of this scenario in terms of lower and/or more stable prices. On the other hand, if LNG terminal operators are able to secure long-term contracts at prices lower than pipeline-delivered prices and pass these terms along to customers, then the region will enjoy some price mitigation and more stable prices.

Security—This option, especially if located next to population centers, poses many safety concerns, which will differ depending on the facility's specific situation. The LNG ships which carry the product are already subject to stringent construction and operational regulations (see LNG Safety and Security discussion on pages 7-8). In December 2004, the Sandia National Laboratories issued a report (the "Sandia Report") on the risks and safety implications of a LNG spill over water. That report found that accidental LNG spills, such as from collisions and groundings, are small and manageable under existing safety policies and practices. The report further determined that risks from intentional events, such as acts of terrorism, can be significantly reduced with appropriate

[70] Anadarko's Bear Head data from Anadarko presentation to PPC on 2/3/05 and M&NE Phase IV presentations. Project assumed to provide 0.360 Bcf/day to New England at a capital cost of $442 million, which includes the cost of the terminal and necessary pipeline expansions.

security, planning, prevention, and mitigation. The hazards associated with specific sites will vary as a function of the proximity of people, buildings, traffic and other conditions. However, in general, the severity of the risks declines as the terminal sites are located away from population centers and the number and costs of required on-shore security measures (e.g. police and fire protection) similarly diminish with the distance from urban population concentrations.

Cost-- The levelized annual capital cost is $648,000/Bcf for 20 years. This includes not only cost of the delivery terminal in Nova Scotia, but also the cost of expanding the Maritimes and Northeast pipeline capacity from 0.6 Bcf/day to 0.8 Bcf/day to enable New England to take advantage of additional vapor from this facility. When the cost of gas[71] is added, this scenario results in a cost of gas displacement of $6.31 million/Bcf.

[71] This calculation assumes an average of $5.66/mmbtu for the cost of natural gas over the study period. This is based on the natural gas prices found in Appendix C.

Creation of Power Generation Using Coal Gasification

Reliability—Assuming for the sake of this analysis that a power plant that burns gasified coal for fuel can be financed and sited in New England, replacing growth in non-gas electric generation with this technology reduces peak day gas demand very marginally. The reserve margins in Table 4-8 assume construction of two 550 MW IGCC plants[72] that comes on line by 2009. This scenario results in positive reserve margins through 2012 under normal and high gas demand with vaporization scenarios.

Table 4-8
Reserve Margins Assuming Coal Gasification Expansion
2005-2012
(Bcf/day)

	2005	2006	2007	2008	2009	2010	2011	2012
	With Vaporization							
Normal Demand	1.25	1.17	1.08	1.16	1.29	1.19	1.09	0.98
High Demand	0.76	0.64	0.52	0.55	0.63	0.48	0.33	0.17
	After Vaporization							
Normal Demand	0.03	(0.05)	(0.14)	(0.12)	0.01	(0.09)	(0.19)	(0.30)
High Demand	(0.46)	(0.58)	(0.70)	(0.73)	(0.65)	(0.80)	(0.95)	(1.11)

Fuel Diversity—This scenario results in considerable fuel diversity benefits because IGCC technology uses coal, a fuel with pricing and sources quite different from traditional pipeline gas sources.

Natural Gas Price Mitigation and Stabilization—There is potential for this scenario to reduce natural gas prices because demand for natural gas from electric generators is reduced. However, uncertainty remains due to the doubt in the ability of regional projects to influence prices that may be determined on an national or international level. The size of this project and the amount of gas displaced due to the high capacity factors found in IGCC technology may reduce some of this uncertainty. There is little or no price volatility with coal, and it is relatively low in price, thus providing price benefits relative to the "no development" scenario.

Security—Examining the security impacts of this option involves comparing the relative security concerns related to fuel delivery. Coal, being a relatively safe fuel to transport, poses minimal security concerns.

Cost—There are no additional gas-related costs due to this scenario. Expansion of coal gasified generation results in additional electric-related capital costs of $1.521 billion. This scenario provides gas displacement at a cost of $3.64 million/Bcf. These costs would be offset by lower overall fuel costs due to the reduction in natural gas use by gas generators.

[72] Assumptions about capital cost, typical size, and fuel cost were taken from AEO 2004. A 90% capacity factor was also assumed.

Expansion of Power Generation Using Nuclear Fuel

Reliability— Assuming for the sake of this analysis that a nuclear power plant can be financed and sited in New England, replacing non-gas electric generation with new nuclear generation results in only very modest reductions in peak day gas demand. The reserve margins in Table 4-9 assume one 1,000 MW plant[73] is constructed and come on line by 2011 (accounting for lead time). The displacement of gas from this scenario results in natural gas reserve margins that are virtually identical to those found in the "no development" scenario.

Table 4-9
Reserve Margins Assuming Nuclear Generation Expansion
2005-2012
(Bcf/day)

	2005	2006	2007	2008	2009	2010	2011	2012
	With Vaporization							
Normal Demand	1.25	1.17	1.08	1.16	1.07	0.97	1.07	0.96
High Demand	0.76	0.64	0.52	0.55	0.41	0.27	0.31	0.15
	With Vaporization							
Normal Demand	0.03	(0.05)	(0.14)	(0.12)	(0.21)	(0.31)	(0.21)	(0.32)
High Demand	(0.46)	(0.58)	(0.70)	(0.73)	(0.87)	(1.01)	(0.97)	(1.13)

Fuel Diversity— This scenario results in considerable fuel diversity benefits because nuclear generation uses a different fuel with pricing and sources that are quite different from traditional pipeline gas sources.

Natural Gas Price Mitigation and Stabilization--There is potential for this scenario to reduce natural gas prices because demand for natural gas from electric generators is reduced. However, uncertainty remains due to the doubt in the ability of regional projects to influence prices that may be determined on a national or international level. The size of this project and the amount of gas displaced due to the high capacity factors found in nuclear generation may reduce some of this uncertainty. There is little or no price volatility with this fuel and it is relatively low in price, thus providing price benefits relative to the "no development " scenario.

Security-- Examining the security impacts of this option involves comparing the relative security concerns related to fuel delivery. Nuclear fuel, while not having the ignition properties of LNG or petroleum, poses security concerns if there is an accident or security situation at the plant or in fuel transit.

Cost-- There are no additional gas-related costs due to this scenario. Expansion of nuclear generation results in additional electric-related capital costs of $1.93 billion. This scenario provides gas displacement at a cost of $3.97 million/Bcf. These costs would be offset by lower fuel costs due to the reduction in natural gas usage by gas generators.

[73] Assumptions about capital cost, typical size, capacity factor, and fuel cost were taken from AEO 2004.

Conclusion

The nine scenarios examined here each manifest unique characteristics and impacts in regard to energy policy goals. Having examined them individually, in Chapter 5 we compare them to one another to identify those that contribute most to achieving one or another of these policy goals.

CHAPTER 5: COMPARING THE CONTRIBUTIONS OF VARIOUS DEVELOPMENT SCENARIOS TO ACHIEVING ENERGY POLICY GOALS

In this Chapter, we compare the nine resource development and demand reduction scenarios to identify those that are likely to be most successful in meeting the region's energy policy goals. We first consider their relative contributions to gas supply reliability, then their relative contributions to fuel diversity, next their relative contributions to price mitigation and stabilization, their relative contributions to security of the gas supply, and finally their estimated costs for delivery or displacement of gas.

Reliability of Gas Supply

In Table 5-1 (below), we offer a look at the relative contributions of these scenarios to gas supply reliability as measured by the enhancement of peak day reserve margins they provide by the year 2012 as compared to current reserve margins. The largest contributions to increasing reserve margins come from the LNG scenarios. Among these, the greatest contribution would be made by an on-shore, in region LNG facility of the size and scope of Weaver's Cove. Contributions to gas supply reliability from the other three LNG scenarios make slightly lesser contributions but are still very substantial. Fuel switching, electric energy efficiency and renewable generation as well as coal gasification and nuclear generation provide positive contributions but to a much smaller degree. Thus, development of any one of the scenarios results in positive reserve margins under the high demand case.

Table 5-1
Comparison of Gas Reliability Enhancements
From Various Scenarios in 2012

Scenario	Normal Demand with Vaporization Bcf/day	Normal Demand with Vaporization % Change over No Development	High Demand with Vaporization Bcf/day
No Development	0.77	--	(0.04)
Fuel Switching	0.96	25	0.15
Electric Energy Efficiency	0.97	26	0.16
Renewable Generation	0.89	16	0.08
On-Shore, In-Region LNG Expansion	1.14	48	0.33
On-Shore, In-Region LNG	1.37	77	0.56
Off-Shore, In-Region LNG	1.19	54	0.38
On-Shore, Out-of-Region Storage	1.13	46	0.32
Coal Gasification	0.98	27	0.17
Nuclear Generation	0.96	25	0.15

On the other hand, no one of the scenarios, developed by itself, is sufficient to provide positive reserve margins in the event that there is no vaporization available at existing sites. While we recognize that this is an extreme scenario, it reinforces the importance of maintaining the current vaporization capacity to maintain gas supply reliability.

Another measure of the reliability enhancements of the various scenarios is the time required to realize benefits, and the relative size of those benefits year to year. Table 5-2 presents a comparison of the various scenarios noting the year they commence and the size of the contribution they make toward gas supply reserve margins each year from 2005 through 2012.

Fuel switching, energy efficiency and renewables generation are assumed to commence promptly as a result of government mandates or funding programs. Among these three, the largest contribution by far is made by fuel switching. The LNG scenarios are assumed to take at least two years longer to begin to produce contributions to improving reserve margins, however their contributions are all substantially greater than those of fuel switching, energy efficiency and renewables generation.

The coal gasification and nuclear generation scenarios have much longer lead times and therefore do not begin to deliver contributions to improving gas reserve margins until much later and their contributions are significantly smaller than the LNG scenarios.

Table 5-2
The Estimated Size and Timing of Enhancements
to Gas Supply Reserve Margins of Various Scenarios
2005 – 2012
Bcf/day

	2005	2006	2007	2008	2009	2010	2011	2012
Fuel Switching	---	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Electric Energy Efficiency	0.05	0.06	0.08	0.10	0.12	0.15	0.18	0.20
Renewable Generation	0.01	0.02	0.04	0.05	0.06	0.09	0.11	0.13
On-Shore, In-Region LNG Expansion	---	---	0.38	0.38	0.38	0.38	0.38	0.38
On-Shore, In-Region LNG	---	---	0.60	0.60	0.60	0.60	0.60	0.60
Off-Shore, In-Region LNG	---	---	0.42	0.42	0.42	0.42	0.42	0.42
On-Shore, Out-of-Region Storage	---	---	0.36	0.36	0.36	0.36	0.36	0.36
Coal Gasification	---	---	---	---	0.22	0.22	0.22	0.22
Nuclear Generation	---	---	---	---	---	---	0.20	0.20

Fuel Diversity

The goal of fuel diversity is best achieved by the electric energy efficiency scenario as well as by the three power generations scenarios that use fuels other than natural gas during peak demand periods: renewables, coal gasification and nuclear generation. In addition, the on-shore, LNG storage scenario provides equally good fuel diversity because it provides additional storage for a system that is critically dependent on storage to meet peak day gas demands.

The other LNG scenarios, because they provide additional gas vapor but no LNG storage capability, are not as effective at meeting fuel diversity goals. However, all the LNG scenarios contribute substantially to improving the regions fuel diversity to some degree because they can provide fuel from a different part of the world than the source of most of our current pipeline gas supplies.

Price Mitigation and Stabilization

Price-related impacts of LNG scenarios will depend on the contracts underlying the development scenario and the level of out-of-region demands for LNG shipments. If out-of-region demand is strong and LNG cargoes are priced according to spot or index prices, then there will be few benefits of this scenario in terms of lower and/or more stable prices. On the other hand, if LNG terminal operators are able to secure long-term contracts at prices lower than pipeline-delivered prices and pass these terms along to customers, then the region will enjoy some price mitigation and more stable prices.

There is potential for the renewables, coal gasification and nuclear scenarios to reduce natural gas prices because each reduces demand for natural gas from electric generators. However, the ability of regional projects to influence prices that may be determined on a national or international level is uncertain, with larger projects (such as the nuclear and renewable expansion scenarios) having greater potential for influencing regional prices. On the positive side, there is little or no price volatility with these three non-gas fuels and coal and nuclear fuels, at least, are relatively low in price relative to natural gas.

Security

In terms of public safety, the least security concerns arise with energy efficiency, renewables and coal gasification. Scenarios that involve the delivery and storage of LNG pose the greatest security threats, especially if the location of the facility is near densely populated areas. Recent studies indicate that the risk of an uncontrolled release occurring during the delivery or storage of LNG is low, especially given the security measures now taken during the delivery of LNG to on-shore terminals. It appears that the consequences would be similar to those that would occur if a tanker full of gasoline were similarly breached and ignited.

Public concerns with the potentially serious consequences of a LNG accident tend to obscure technical assessments that the risk of such an incident is low. Regulators must ensure these concerns are addressed when evaluating the relative merits of alternative LNG delivery and storage scenarios.

Cost Impacts

In Table 5-3 we compare the relative cost of these scenarios on the basis of the cost incurred to provide additional or displace expected gas supplies. Fuel switching by gas-fired power generation capacity to burning oil at peak gas demand periods is estimated to be the least cost scenario (aided by the assumption that no capital cost would need to be incurred to enable an additional 1,000 MWs of such capacity to switch). This is true when distillate oil is substantially more expensive than natural gas as well as when it is only slightly more expensive.

Electric energy efficiency expansion is the next least costly scenario. (We would expect gas energy efficiency, if implemented on the ambitious scale as that contemplated under the electric efficiency scenario to be at least as cost effective if not more so.) Additions of new coal gasified electric generation and new nuclear generation are next most costly, followed by expanded renewable electric generation. These indicate that trying to reduce gas consumption through increased electric generation using other fuels is a more expensive proposition than demand reduction.

The expanded LNG scenarios are the most expensive of all, not because of their capital costs (which are relatively modest compared to the other scenarios) but mainly because the cost of natural gas itself is so high.

Table 5-3
Comparison of Gas Delivery or Displacement Costs of Various Scenarios

	Million $/Bcf
Fuel Switching	
Low Oil Price Premium	0.61
High Oil Price Premium	1.18
Electric Energy Efficiency	2.82
Renewable Generation	4.50
On-Shore, In-Region Expansion	5.77
On-Shore, In-Region LNG	5.97
Off-Shore, In-Region LNG	6.17
On-Shore, Out-of-Region Storage	6.31
Coal Gasification	3.64
Nuclear Generation	3.97

APPENDICES

Appendix A

NEW ENGLAND GOVERNORS' CONFERENCE, INC.

RESOLUTION NUMBER _____

A RESOLUTION ON THE USE OF NATURAL GAS TO GENERATE ELECTRICITY IN NEW ENGLAND

WHEREAS, natural gas is a major and growing source of energy throughout the United States; in New England it accounts for 18% of the region's total energy consumption and approximately 40% of the fuel used to generate electricity in 2003; and

WHEREAS, use of natural gas is projected to be an even larger portion of the region's fuels used to generate electricity because of its positive environmental characteristics relative to other fossil fuels; and

WHEREAS according to the National Petroleum Council Report of September 2003, "North America is moving to a period in its history in which it will no longer be self-reliant in meeting its growing natural gas need…"; and

WHEREAS, liquefied natural gas (LNG) currently plays a vital role in meeting the region's winter-time space heating needs; and

WHEREAS, New England currently has one LNG delivery and regasification terminal that serves as a critical link in the region's energy infrastructure; and

WHEREAS, there are several proposals to develop additional LNG delivery and regasification terminals in or near the New England region; and

WHEREAS, the increased use of LNG will bring with it increased concern for security of fuel deliveries and public safety; and

WHEREAS, increased use of natural gas, including LNG, may modify the mix of fuels used to generate electricity;

NOW THEREFORE, BE IT RESOLVED, that the Power Planning Committee shall analyze current and projected use of natural gas and LNG and identify any actions that should be taken to strengthen the region's energy and fuel diversity position in light of projected developments in the electricity market; and

BE IT FURTHER RESOLVED, that the Power Planning Committee report its findings and any actions it recommends be taken by the Governors or others to strengthen the region's energy position with respect to the use of natural gas, LNG, and other options to meet its energy needs; and

BE IT FURTHER RESOLVED, that this report be presented to the Governors on the occasion of the February 2005 meeting of the New England Governors Conference, Inc.

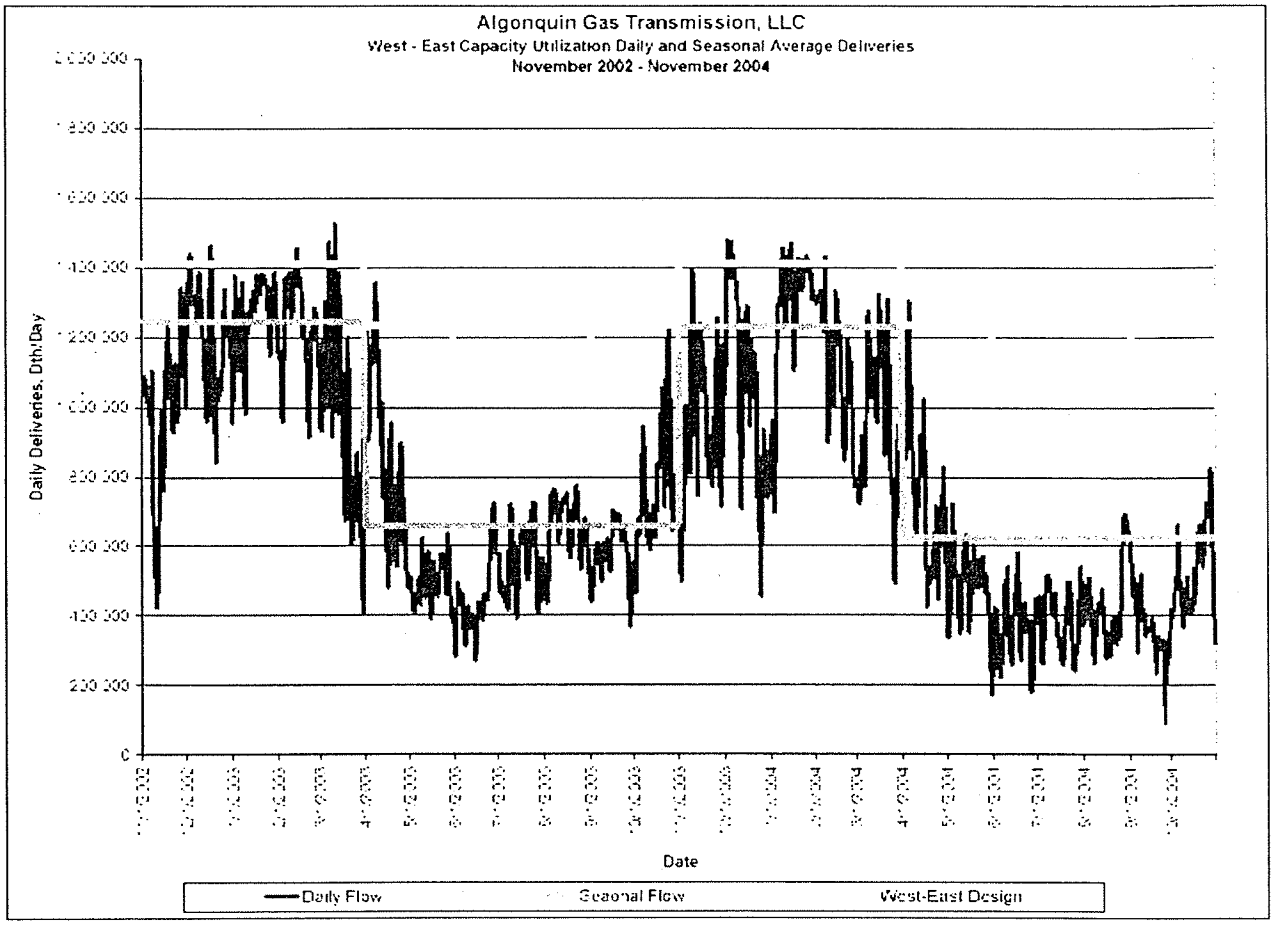
This resolution is effective immediately.

ADOPTION CERTIFIED BY THE NEW ENGLAND GOVERNORS' CONFERENCE, INC. On September 10, 2004.

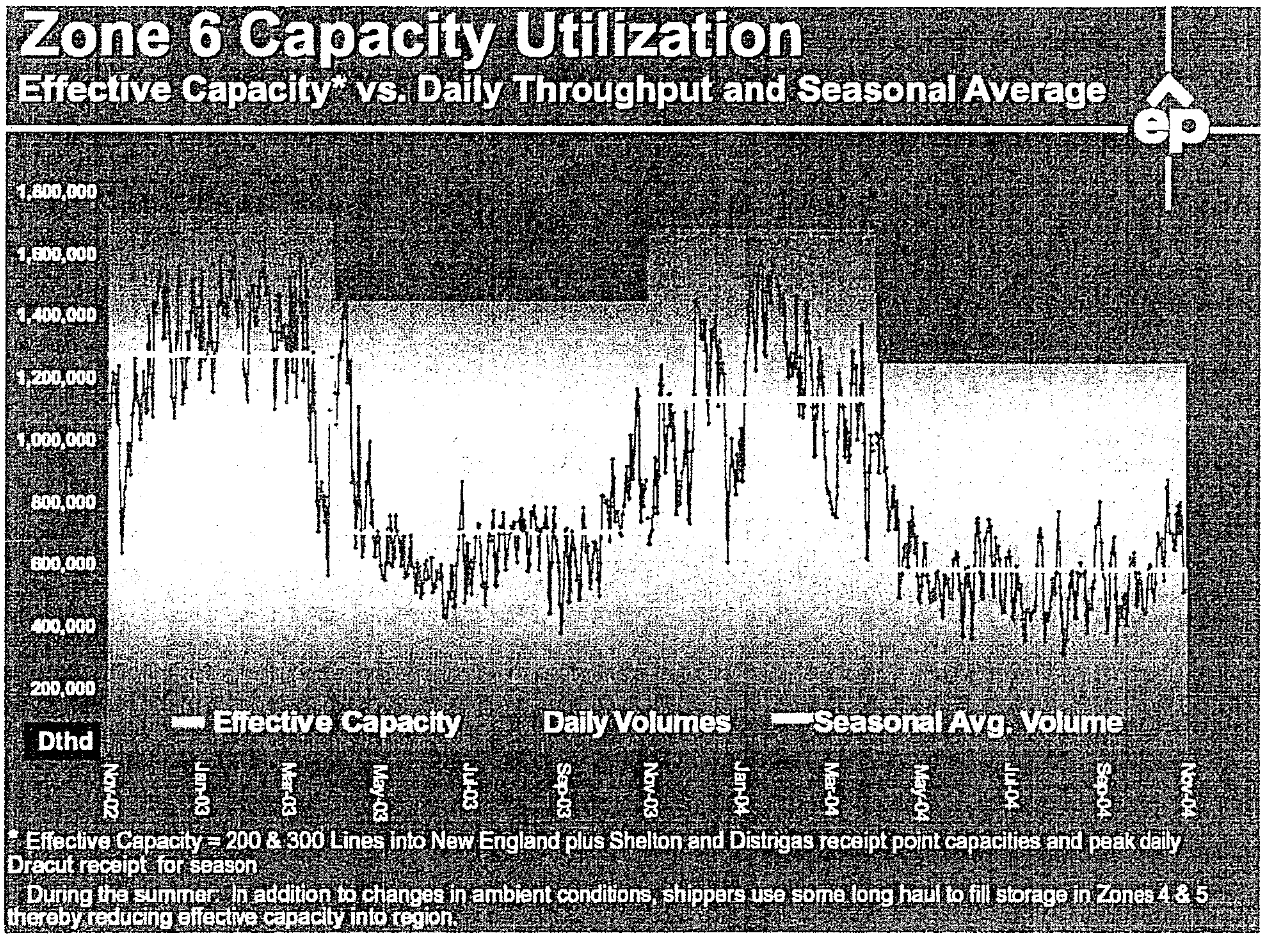
____

James H. Douglas
Governor of Vermont
Chairman

Appendix B
Algonquin and Tennessee Pipelines Daily Throughput November 2020 to November 2004



Tennessee Gas Pipeline
Zone 6



Appendix C

Underlying Assumptions to Forecasts of Natural Gas Demand by Electric Generators

	2004	2005	2006	2009	2012	2015	2018	2021	2024
Total Power Generation Capacity (MW)									
AEO 2004 (1)	32,630	32,640	32,650	31,510	32,040	32,800	33,960	35,440	37,570
RGGI (Draft) (2)	n/a	n/a	31,038	33,331	35,352	36,936	38,744	40,407	42,012
ISO-NE (summer) (3)	32,658	32,965	32,925	33,997	33,990	n/a	n/a	n/a	n/a
EEA (4)	33,262	32,494	32,543	33,176	34,013	35,003	37,398	n/a	n/a
Natural Gas Incremental Capacity (MW)									
AEO 2004 (1)	0	0	0	0	410	670	490	770	1160
RGGI (Draft) (2)	n/a	n/a	0	876	861	891	962	1043	1090
ISO-NE (3)	535	267	0	1073	0	n/a	n/a	n/a	n/a
EEA (4)	0	0	0	487	779	928	1368	n/a	n/a
Renewable Incremental Capacity (MW)									
AEO 2004 (1)	60	20	10	150	130	60	290	320	950
RGGI (Draft) (2)	n/a	n/a	597	1362	1121	694	859	676	515
ISO-NE (3)	0	0	0	0	0	0	0	0	0
EEA (4)	16	17	17	54	60	62	141	n/a	n/a
Power Plant Heat Rates (Btu/kWh)									
AEO 2004 (1)	7,444	7,444	7,444	7,444	7,056	7,000	7,000	7,000	7,000
RGGI (Draft) (2)	7,444	7,444	7,444	7,444	7,056	7,000	7,000	7,000	7,000
ISO-NE (3)	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
EEA (4)	7,846	7,782	7,688	7,716	7,716	7,703	7,632	n/a	n/a
Gas Price to Generators (2004$/mmBtu)									
AEO 2004 (1)	5.07	4.61	4.50	4.70	5.03	5.48	5.58	5.65	5.61
RGGI (Draft) (2)	n/a	n/a	7.03	7.01	6.66	6.16	5.70	5.47	5.27
ISO-NE (3)	5.18	4.35	3.52	3.93	4.32	n/a	n/a	n/a	n/a
EEA (4)	7.25	8.33	7.87	6.65	6.56	5.90	6.08	n/a	n/a
Oil Price to Generators (2004 $/mmBtu)									
AEO 2004 (1)	5.98	5.50	5.40	5.35	5.33	5.54	5.75	5.91	6.00
RGGI (Draft) (2)	n/a	n/a	7.18	6.49	5.35	6.37	5.40	5.46	5.52
ISO-NE (3)	7.01	6.19	5.37	5.47	5.74	n/a	n/a	n/a	n/a
EEA (4)	8.56	9.37	8.05	6.54	6.10	6.02	5.93	n/a	n/a